Status of Goldstone Solar Energy System Study of the First Goldstone Energy Project

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This article summarizes the results reached by the DSN Engineering Section and private consultants in the review of the initial plan of the Goldstone Energy Project. The main objectives were in the areas of energy conservation and the application of solar-driven systems for power and hydrogen generation. This summary will provide background data for management planning decisions both to the DSN Engineering Section and other organizations planning a similar program. The review showed that an add-on solar driven absorption refrigeration unit with its associated changes to the existing system was not cost-effective, having a payback period of 29 years. Similar economically unattractive results were found for both a solar-hydrogen and a wind-hydrogen generation plant. However, cutting the hydrogen generation linkage from this plant improved its economic feasibility.

I. Introduction

As part of a broad program to conserve energy at government installations, the Jet Propulsion Laboratory examined the concept of operating one or more of its installations on clean, renewable gaseous fuels such as hydrogen or methane. The sun would be the primary source of energy in addition to other sources such as wind and municipal waste. The project was called "Goldstone Energy Project," and the goals were set to provide a system which would (1) save a significant amount of fossil fuel or commercial electric power, (2) be economically competitive with existing energy sources, and (3) minimize harmful effects to the environment and be architecturally attractive.

The installation under investigation was the Goldstone Deep Space Communication Complex (DSCC) at Goldstone, California. Six separate tracking stations and a Microwave Test Facility (MTS) were included in the complex. The Goldstone installation has some unique characteristics which made it appropriate for consideration, such as:

(1) The site is located in the Mojave Desert, which receives abundant sunshine and significant wind currents.

(2) The tracking stations are surrounded by a large land area (approximately 80 km^2), with potential for collecting solar energy while not interfering with space communications.

(3) Existing diesel engine generating capacity (12.4 MW_e) is operated only during a critical phase of space flight missions or during emergencies such as failure of commercial power. The Goldstone facility has an average electric demand of 3.5 MW_e, which is normally purchased from a utility company, and the concept of running the engine generators on a continuous basis instead of purchasing power presents a possible saving to be studied.

The original objectives of the energy program, to support the national goal of energy independence, were set in the initial stages of the project to (1) reduce the DSCC energy consumption by 30 to 40% over a 5-year period starting in 1974, (2) reduce the fossil fuel consumption by 70 to 90% over a 5-year period starting in 1976, and (3) attain a high degree of energy self-sufficiency during the period of energy utilization nationwide.

The original Goldstone Energy Project was a path-seeking study which could be identified as a "hydrogen based study." Later on, the project objectives were changed and the title became the "DSN Energy Conservation Project," a change that was made to express in more specific terms the new project goals brought on by the conclusions drawn from the first path-seeking study. The above phases are explained as follows:

A. Hydrogen Based Study

A baseline configuration had been proposed whose main objective was the production of hydrogen gas by water electrolysis. The electric power needed for electrolysis would be provided by a combination of a wind power plant and a solar-thermal-to-electric power plant. The generated hydrogen was to be used as a fuel for either heating purposes or for driving the standby diesel engines. During the early stages of the project and the development of the baseline configuration, a joint study effort had started between the DSN Engineering Section at JPL and Cornell University in Ithaca, New York. This study effort looked into the changes that would be required to the existing diesel fueled engines provided that the implementation of hydrogen gas became economically feasible.

Another addition to the baseline configuration which was made late in the program, was the solar driven heating, ventilation and air conditioning (HVAC), using the absorption refrigeration method. This report ties together this last addition to the Project and reports on its status.

Two different private consultants (Refs. 1-3) were selected to assist in answering the questions raised during the study. First, Keller and Gannon Consulting Engineers were assigned the task of estimating the heating and cooling loads for Goldstone buildings and evaluating many potential money-saving energy conservation ideas. Second, Burns and Roe, Inc., Consulting Engineers, followed the Keller and Gannon work and gave their own input to the Projects as a whole with a more detailed analysis.

This first phase of the Goldstone Energy Project ended with a set of technical recommendations that contributed to the scope of a broad energy project now called "DSN Energy Conservation Project".

B. DSN Energy Conservation Project

The DSN Energy Conservation Project embodies the Energy Conservation Awareness and Recognition Program (ECARP), Building Modification Program, and Utility Control System (UCS). These programs are underway and the status of their progress will be the subject of other articles to come.

II. Solar Energy System Outline

The proposed Goldstone solar energy baseline system outline is presented in detail in Refs. 4 and 5, and briefly stated in this report for convenience. It consists mainly of the following alternate subsystems: (1) "central complex" for all tracking stations, (2) "central site" for each tracking station, or (3) "distributed" units for each installation. The common outline is shown in Fig. 1 and is composed of the following:

(1) *Solar Energy Collection Subsystem.* This subsystem consists simply of a set of solar collectors and heat storage tank(s) which would supply most of the thermal energy required to operate a power generation subsystem and a solar heating and cooling subsystem.

(2) *Solar Heating and Cooling Subsystem.* This subsystem, added late in the baseline configuration, takes in a large percentage (85%) of its thermal energy requirement from the solar-energy collection subsystem; the rest is supplied by another energy source such as propane gas heating. This subsystem supplies water heating and space-air heating for the facility and provides all the air conditioning requirements through absorption refrigeration units.

(3) *Power Generation Subsystem.* This consists of both a solar-power subsystem and a wind-power subsystem. The solar-power subsystem includes a heat engine working with a technically advanced power cycle, a cooling tower, and a device for energy storage. The

wind-power subsystem consists of a set of air turbines connected to electric generators, and a device for energy storage. This subsystem would provide direct current (dc) electric power to the electrolysis subsystem and other system accessories.

(4) *Electrolysis (or Hydrogen) Subsystem.* This consists of a set of electrolyzers, hydrogen storage tanks, and an electric distribution system. The electrolysis subsystem is a combination of a wind-hydrogen subsystem and a solar-hydrogen subsystem, as shown in Fig. 1. Hydrogen was to be used directly for heating purposes and/or considered as a fuel for the engine-generators.

(5) *Waste Heat Utilization Subsystem.* This subsystem makes use of the direct waste of energy such as hot flue gases, exhaust steam or hot streams of water from cooling systems, and the energy from municipal waste incineration. The waste heat utilization subsystem assists in providing the thermal energy for the power generation subsystem. The present report considers only the efforts made to convert the existing diesel-generators to a total energy system using waste heat recovery and generated electric power to heat, cool and power the Goldstone facilities.

III. Bases for Evaluation

The following is a list of criteria considered for evaluating each candidate subsystem configuration:

(1) Minimum life-cycle cost.

(2) Maximum personnel safety.

(3) Minimum environmental impact.

(4) Ability to support the national goal of energy independence.

(5) A system whose performance can be predicted fairly accurately.

(6) Minimum use of land area with no interference with tracking and data acquisition functions.

(7) Minimum manpower requirements for maintenance and operation.

(8) Long operational life.

(9) Flexibility to relocate individual modules.

(10) Minimum replacement cost in case of destruction by natural hazards.

IV. Solar Energy Collection Subsystem

The performance and cost analysis of the following five types of solar collectors were studied (Ref. 1):

(1) A flat plate collector.

(2) A compound parabolic (Winston type) collector.

(3) A tubular collector (Corning type).

(4) A parabolic trough collector.

(5) A paraboloid dish collector.

The cost ranged from \$60/m^2 for a low-performance flat plate collector to \$293/m^2 for the paraboloid dish type. The annual thermal output for the Goldstone location ranged from 900 kWh_t/m^2 for the low-performance flat plate collector to 1470 kWh_t/m^2 for the compound parabolic type. In this study, nontracking, high-performance solar collectors which would be commercially available by 1980 were selected. However, it was later found that no collector presently available or in an advanced state of development could support an energy-on-demand system on an economically attractive basis when compared to fossil fuels at current prices.

V. Solar Heating and Cooling Subsystem

The economic evaluation of a conceptual solar heating and cooling design serving the four major buildings at DSS 12, namely, Administration and Cafeteria (G-21), Control Building (G-26), Engineering and Communications (G-33), and Network Laboratory and Maintenance (G-38), was performed. The results indicated that solar heating and cooling of these four major buildings, using an add-on absorption refrigeration unit, was not economically feasible, having a payback period of 29 years as will be shown later in Table 1. The estimate is dominated by the piping and valve cost needed both for the collectors and the cost of new fan-coil units. The collectors would be less costly if they were located near, or on top of, the buildings they serve. Also, solar heating, ventilation and air conditioning (HVAC) would be less costly if they were considered for existing buildings that do not have a predominant daytime load and would only be attractive for buildings requiring complete replacement of HVAC equipment. The rationale of these findings is described below.

A. Subsystem Criteria

Presently the above four buildings at DSS 12 are air conditioned by conventional systems, utilizing gas-fired boilers for heating and electric driven vapor compression refrigeration units for cooling (with "direct expansion" from the evaporator coils to the air handlers). The proposed solar-assisted HVAC system was designed as a "centralized" unit. Hot water for heating and chilled water for cooling are produced in a central station on-site and then distributed to the different buildings. The following criteria are the bases of the study:

(1) System component selection is based on current technology production. Cost estimates are based on 1976 prices with 10% annual escalation.

(2) Solar collectors are of the nontracking type.

(3) The solar energy contribution to the total annual heating and cooling requirement for the four major buildings at DSS 12 is 85%. This percentage was chosen since it is not economical to size the solar collection subsystem to provide 100% of the load.

(4) Solar collectors are not to be located on the roofs of buildings but on the ground.

(5) Existing HVAC systems are to remain intact and serve as backup for the solar-assisted types.

(6) An auxiliary hot water heater is operated when the solar collector system is unable to meet the load. This heater has to be sized to meet the peak load to allow full operation without solar input.

A schematic of the system is shown in Fig. 2.

B. Heating and Cooling Load

The existing heating and cooling systems for the four major buildings at DSS 12 are multizone systems which require simultaneous heating and cooling. Two main classes of HVAC loads were considered:

(1) Loads that are associated with comfort areas such as offices and conference rooms.

(2) Loads that have a continuous demand such as electronic rack cooling in the communication and the control rooms.

The load analysis was originally made by Keller and Gannon (Ref. 3) using a computer program called ECUBE.[1] The daily heating and cooling loads for each building were updated and calculated for typical weekdays[2] of each month. The existing heating load was later planned to be reduced by 97% to become 40,300 kWh_t/year, and the buildings cooling requirement to be reduced by 45% to become 1,146,000 kWh_t/year. These reductions, claimed by Burns and Roe following the Keller and Gannon study, can be achieved if separate fan-coil units were used instead of multi-zone units.

[1] Energy Conservation Utilizing Better Engineering.

[2] The heating and cooling loads were based on (1) weekend daily requirement = 60% weekday daily requirement, and (2) 22 weekdays/month and 8 days weekends/month.

Regarding peak loads, the claimed energy conservation measures would also reduce the peak heating load by 77% of the existing system to become 97.3 kW_t and the peak cooling load by 33% to become 380 KW_t. The cooling demand for the four major buildings was then estimated as 100 tons of refrigeration.

C. Solar Radiation Model

This study was developed using the ASHRAE clear day model with corrections for unclear day effects from climatic Atlas data and from actual measurements (Ref. 6). A collector tilt angle of 35 deg to the horizontal and facing south was selected based on optimization of the maximum annual solar radiation at the Goldstone area.

D. Sizing the Solar Collector

The selection of the solar collector was made from those units which are (1) commercially available or very near to the production stage, (2) able to produce relatively high fluid temperature around 100°C at good efficiency (this requirement is essential to drive an absorption type air conditioner), and (3) of low first cost with a minimum maintenance.

In the studies made by Burns and Roe, the high-performance NASA-Honeywell flat-plate collector with a black nickel selective coating and a double glass cover and antireflective coating was selected. The annual average energy collected per day is 5 kWh_t/m^2 or 1800 kWh_t/m^2 per year. The calculated collector field area, based on solar assistance of 85% of the total heating and cooling energy consumption, was found to be 1600 m^2.

E. Energy Storage

There are basically two approaches to sensible heat storage, one uses two separate hot and cold storage tanks and the other a single stratified storage tank. The primary advantage of the first approach is that the hot and cold fluids are separated. However, its disadvantage is that each of the two tanks must be sized to hold the full storage capacity. In the case of a stratified tank, mixing can be prevented by using a separator such as a piston or a floating membrane, and this type costs approximately one half that of the first approach. However, Burns and Roe (Ref. 1) used the two tank approach. Each tank was sized at 156 m^3 to carry a net volume of fluid of 139 m^3. An alternate configuration is described under paragraph H below.

F. Refrigeration and Air Conditioning Units

Five 25-ton LiBr/water absorption refrigeration units were selected to provide a total of 125 tons (440 kW_t) of cooling capacity, which is a little more than needed to meet the peak cooling load of 380 kW_t. The cooling water necessary to operate the condenser and the absorber sections is provided by two wet cooling towers with a continuous supply of cooling water at 23.9°C (75°F). The chilled water produced in the evaporator is supplied to the chilled water storage tank and is kept at 7.2°C (45°F).

G. Flow Control — Solar Collector Loop

Since water alone is used as the working fluid, it was suggested that an auxiliary system be provided to drain the collector into an insulated tank at sunset to prevent nighttime freezing. Other alternatives such as circulation of a slow flow of warm water from the storage tank were eliminated since this results in some loss of the energy collected during the day. Also, the use of an ethylene glycol/water mixture was not recommended due to high cost. The flow control mechanism was very complicated due to the introduction of an anti-corrosion gas (nitrogen) in a pressurized loop which is drained by gravity. The loop is equipped with temperature sensing devices to monitor the flow rate vs the collector exit temperature through control valves so that the storage tanks always receive the fluid at a uniform pre-assigned temperature (107°C), irrespective of any variations that might occur due to ambient or solar radiation conditions.

H. Alternate Configuration

An alternative to the solar heating and cooling subsystem was presented, utilizing the same absorption refrigeration units but with a solar collector other than the NASA-Honeywell flat-plate type. A tubular collector, recently manufactured by Owens-Illinois Corp., was selected as the candidate.[3] The collector possesses a higher accumulated thermal efficiency per day (about 45%) and a lower heat loss rate to the surroundings than the comparative flat-plate type. The steady-state behavior of this collector was given in Ref. 7. Also, its unsteady-state (transient) thermal response to the time-changing input parameters was analyzed by two different methods; an analytical method (Ref. 8) and a finite difference numerical method (Ref. 9). The results indicated that with a 50/50 mixture of ethelyne glycol/water solution as a working fluid, the instantaneous collector efficiency can reach 60% and an accumulated daily efficiency[4] of 43% under a typical Goldstone weather spectrum (Ref. 9).

A lithium bromide/water absorption refrigeration unit was selected for the study based on its higher coefficient of performance relative to other absorption refrigeration types and on the current manufacturer's efforts to mass-produce small-size units at a low cost. A detailed computer model for such a unit was reported in Ref. 10. The coefficient of performance ranged from 0.6 (at peak cooling load) to 0.8 (at average load). With a solar energy share of 85% of the total demand and an average cooling capacity of 100 tons of refrigeration, the collector area was found to be 1460 m^2.

A stratified tank was considered as a part of this alternative study with a semifloating separator between the hot and cold fluids. The energy fluctuations for one-day storage (approximately 8 hours of hot fluid charging and 16 hours of discharging) indicated that the necessary tank volume should be at least 120 m^3. Also, it was found that about three times this tank capacity would be required if the tank was designed for double the collector area and a two-day storage (approximately 8 hours of hot fluid charging and 40 hours of discharging) wherein one of the two days was assumed fully cloudy with zero input solar energy.

Regarding cost, this alternate configuration was not analyzed separately since it requires the same costly alterations and additions to the existing HVAC systems as the previously mentioned configuration.

I. Conclusions of the Solar Heating and Cooling Subsystem

The cost estimates of the proposed solar heating and cooling system at DSS 12, as presented in Table 1, are shown to have a long payback period (29 years). Therefore, it is concluded that a solar assisted system, with the components and alterations as outlined in this study, is not an economically feasible alternate to the existing system.

The principal capital cost items, as shown in Table 1, are the new piping, fan-coil units and ducts which represent 40% of the total installation cost. As a result of adopting the absorption refrigeration technique, these items are needed to convert the existing system, which utilizes direct expansion of refrigerant (R-22) in the cooling coils, to a new system with a chilled water circuit. Accordingly, if an economically viable air conditioning system has to be installed, a new direction of efforts has to be followed excluding the absorption refrigeration method, wherein the existing mechanically driven air conditioners, ducts, pipes, etc., are kept intact to save a considerable amount of new installation costs.

It should not be concluded that a solar-assisted HVAC system would be uneconomical in all situations. Since we are keeping the existing HVAC systems intact, a new and different approach must be considered to reduce the new add-on

[3]This was considered the best collector commercially available at time of initial study.

[4]Manufacturer recommended fluid exit temperature not more than 120°C for coating protection.

installation cost. However, for a newly constructed system, the application of solar-assisted absorption technique may result in an economically feasible case.

VI. Wind-Hydrogen Subsystem

A. Wind Turbines

A detailed technical review about wind power and air turbines design was presented in Ref. 1. It included two general categories: the horizontal axis wind turbine and the vertical axis type.

(1) *Horizontal Axis Turbine.* This consists of a number of blades (2-12) of an airfoil shape radially distributed around a horizontal shaft with the blades rotating in a vertical plane. The blade pitch may be fixed or variable. The maximum rotor efficiency is reached during intermittent operation only if the blade tip speed is kept proportional to the wind speed. In practice, each turbine-generator is designed for a specific cut-in speed and a cut-out speed.[5] The optimum blade tip-to-wind speed ratio ranges from 2.5 (for slow speed multibladed propellers) to 6 (for high speed types).

(2) *Vertical Axis Turbine.* This offers several advantages over the horizontal axis turbine such as: (1) the ability to accept winds from any direction, (2) suitability for low range of wind velocities, (3) the generator and controls can be set on the ground for simpler tower construction, and (4) lower cost. Examples of this design are the "Savonius" rotor (a modified S-shape rotor) and the "Darrieus" rotor (consists of 3 airfoil blades having a common chord on a vertical shaft transverse to the wind currents).

A two-blade propeller rotor (horizontal axis) and a three-blade Darrieus rotor (vertical axis) are analyzed and their cost determined.[6]

In the process of evaluating and selecting the components of the wind subsystem, the relationship between the turbine design and cost projection was made. The feasibility of using batteries or flywheels as a means of leveling wind power generated during intermittent unsteady wind durations was studied. The selection of the best configuration was based on the one that possesses the lowest 10-year life cycle cost. The results indicated that the vertical axis turbines meet all the technical and cost effectiveness requirements.

The baseline wind subsystem configuration was set as an array of the "Darrieus" type coupled with a small "Savonius" type wind turbine as an auxiliary device to provide self-starting.[7] Each wind turbine drives an electric generator directly or through gearing. The self-starting device is a small generator-motor to start the big wind turbine which can operate as a low capacity generator during low wind speed periods with an overall conversion (from wind to shaft power) efficiency of 35%. The generators operate at rated capacity when the wind velocity reaches or exceeds the maximum design value. The wind subsystem is proposed to be modular, with each module having an output of 300 kW_t of hydrogen when connected to the electrolyzer.

B. Electrical Generators for Wind-Subsystem

The wind turbine generator may be classified as follows:

(1) *Constant speed generator (synchronous generator or induction generator).* The speed of the turbine rotor is controlled by means of a speed governor which changes the pitch of the propeller blades. The power generated is ac with a constant frequency (60 Hz). The generator is disconnected from the load by using a circuit breaker when it is no longer possible to regulate the speed or frequency.

(2) *Variable frequency/speed generator.* This is either: (a) A dc generator: the output may be used directly to supply a dc load or through an inverter to supply an ac load (b) An ac generator: the output is variable frequency ac. To supply a constant frequency load, a frequency converter is used. Also, to supply a dc load, a rectifier has to be used such as silicon controlled rectifiers (SCR).

Regarding cost, ac generators were recommended for economic and efficient electric power transmission for the proposed wind turbines at the Goldstone site. The vertical axis Darrieus-type rotor connected to two induction generators of squirrel-cage type appeared to be practical and cost effective.

The above selection of the candidate turbine-generator module was based on the relationship between the

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[5] The cut-in speed is the minimum wind speed for energy conversion and the cut-out speed is the maximum speed allowed due to structural limitation.

[6] The 1977 installation cost of a 300-kW_e-capacity propeller wind turbine with 73.5 m (241 ft) rotor is estimated at $715,000 or $2383/$KW_e$. It produces 720,000 kWhr/year at Goldstone with an energy cost of $0.11/$kW_e$h based on 10-year operation. On the other hand, the installation cost of a 200-kW_e-capacity vertical axis wind turbine of the Darrieus type with a 27.4 m (90 ft) rotor is estimated at $110,000 or $550/$kW_e$. It produces 120,000 kWhr/yr at Goldstone with an energy cost of $0.10/$kW_e$h.

[7] Darrieus type blades stall at low blade tip-to-wind speed ratio approx 3; the optimum ratio for maximum power ranges from 4.75 to 6.

fundamental design features of the two main turbine types: vertical and horizontal axis, and the appropriate projections of their installed cost, energy cost, operation and maintenance cost, together with the effects of Goldstone wind requirements on performance. According to the rough wind data taken at Goldstone, the average wind speed is very low to be exploited as a source of energy. Since the energy cost can be lowered substantially should the average wind speed data be improved, it is recommended that additional site data be gathered over longer periods of time and neighboring locations to establish a more accurate wind velocity map.

C. Electrolyzers for Hydrogen Generation Subsystem

The following three types of electrolyzers were considered:

(1) *Tank-type electrolyzer.* Acts as one reversible cell consisting of two alternate polarity electrodes (anode (+) and cathode (-)) made of flat sheets of steel welded to the bus bars. A diaphragm, usually made of asbestos is used to separate the hydrogen generated at the cathode from the oxygen generated at the adjacent anode. The system can operate at atmospheric pressure as well as low or high pressure.

(2) *Filter-press electrolyzer with alkaline electrolyte.* This unit is constructed from a set of alternate bipolar electrodes and asbestos diaphragms. One side of the electrode is the cathode of one cell while the opposite side is the anode of the adjacent cell. The set may operate at pressures above atmospheric (~ 30 atm).

(3) *Filter press electrolyzer with solid polymer electrolyte.* The electrolyte in this case is not liquid but rather a 10-mil sheet of a polymeric structure coated with a thin film of catalyst (a form of Teflon) to form a barrier between the generating oxygen and hydrogen as well as providing a high ionic conductivity.

These different types of commercial electrolyzers under study have conversion efficiency (defined as the ratio of low heating value of hydrogen production rate/electrical energy supplied) ranging from 60 to 90%; the installation cost for every pound of hydrogen/hr ranges from \$4000 to \$7500, respectively.

D. Wind-Hydrogen Subsystem Configuration and Cost

Two wind-subsystem module configurations were studied for comparison, both technically and economically: (1) a centralized module having a nominal capacity of 300 kW_t of hydrogen, (2) a distributed module consisting of 10 isolated submodules, each having a nominal capacity of 30 kW_t of hydrogen. Their components were selected as follows:

(1) The "centralized" wind-subsystem includes an array of 10 vertical-axis wind turbines of 200 kW_e each (a Darrieus turbine coupled with a self-starter Savonius for each), a high-voltage ac transmission system, and four electrolyzer units of the tank type working at atmospheric pressure. Each electrolyzer unit has a full load capacity of 78.5 kW_t of hydrogen.

(2) The "distributed" wind-subsystem consists of 10 isolated vertical axis turbines (same as centralized configuration) and 10 electrolyzer units of the tank type with a capacity of 31.4 kW_t each.

The cost estimates for each configuration is presented in Tables 2 and 3.

The tank type electrolyzer was chosen since it is simple in construction, requires less maintenance and can be operated at low partial loads down to 5% of full capacity. In the centralized plant, four electrolyzer units of 78.5 kW_t full load capacity each, consume 138 kW_e/unit of electric power (a thermal conversion efficiency of 57%) or a total electric consumption of 552 kW_e and produces 314 kW_t of hydrogen (equivalent to a hydrogen production rate[8] of 9.43 kg/hr). For a typical day at Goldstone, the on-site data indicates that the periods during which the wind speed exceeds the minimum cut-in speed is about 25% of the time as an annual average (i.e., 6 hours per day). Accordingly, the electrolysis plant will require an annual electric input of 1.209×10^6 kWh_e/yr, and 10 wind turbines of 120,000 kWh_e/yr capacity are needed. Each turbine-generator is rated at 200 kW_e each at 35 mph rated velocity. Provision for storing mechanical energy for leveling the power fluctuations can be accomplished in different ways, such as high-speed flywheels or batteries.

In the "distributed" plant, the accumulated cost of 10 electrolyzers of 31.4 kW_t capacity each (replacing the 4 larger units for the "centralized" plant), the cost increase brought by using dc generators instead of ac, and the cancellation of electrical transmission system, will yield a minor difference in the 10-year life cycle cost per kW_t of hydrogen as shown in Tables 2 and 3. Although the "distributed" subsystem configuration is slightly higher in cost than the centralized subsystem, it was selected in view of its adaptability to be relocated to alternate windy sites and the suitability of the small size units to mass production.

[8]This is based on the lower heating value of hydrogen, which is 28,900 kcal/kg. The reversible (minimum) work necessary to produce 1 kg of hydrogen by electrolysis at 25°C is 27,320 kcal or 31.77 kWh_e.

It should be pointed out that it would not be economical to consider a wind-hydrogen plant without energy storage and leveling devices. Without this storage, four times the capacity of the electrolyzers would have been installed in order to meet the peak power possibly generated by the turbines (about 6 hours/day) as determined by the Goldstone wind spectrum.

VII. Solar-Hydrogen Subsystem

The solar-hydrogen subsystem is composed of solar collectors, heat engine, dc generator, and an electrolysis unit. This subsystem was assumed modular, with each module producing an output of 300 kW_t of hydrogen. Two approaches to solar thermal-to-electric power generation were studied (Ref. 1) as follows:

(1) Using a large thermal storage, one heat engine and one electrolysis unit to generate 300 kW_t of hydrogen on a continuous basis for 24 hours a day.

(2) No thermal storage is used and three heat engines and electrolysis units rated at 300 kW_t of hydrogen each are used to provide 900 kW_t of hydrogen for only 8 hours/day (sunshine period).

In the two approaches, the collector area used would be equal if the average fluid temperature was kept the same. The main difference between approaches (1) and (2) is that approach (1) utilizes a large storage tank and approach (2) adds two heat engines and two electrolyzers, as shown in Fig. 3.

The result of the analysis showed that approach (1) is less expensive than approach (2). However, *neither of the above two approaches is economically viable* due to the repetitive energy conversion from solar thermal to electrical to thermal again in the form of hydrogen. The design and cost of each component was analyzed as follows:

(1) *Solar Collectors.* Two nontracking collectors (a high-performance flat plate collector and the compound parabolic (Winston) type) were compared in performance and cost. The two collectors were selected among a list of commercially available types (Ref. 1). The high-performance flat plate collector was then recommended based on its minimum 10-year life cycle cost. The collector size was found to be 16,250 m^2 for a module producing 300 kW_t of hydrogen with an electrolyzer conversion efficiency of 57%, a heat engine generator efficiency of 21% (based on a uniform storage of fluid at 205° C), and a yearly average of the collector output per day of 3.70 kWh_t/m^2 (annual output of 1350 kWh_t/m^2). The total daily collector output will then be 60,120 kWh_t.

(2) *Thermal Storage.* Only thermal energy storage in the form of sensible heat of water is recommended. By selecting different hot storage temperatures, the amount of stored water was calculated based on a ratio of 2/3 of the collector output per day, i.e., to store 40,080 $kWhr_t$ per day. The number of tanks, tank dimensions, weight, insulation, pumping power and cost were calculated, and the selection was based on the least cost configuration. For a set of tanks partially buried underground, the cost per kWh_t stored ranged from \$21.9 to \$31.2 for different pressurized fluid circuits. The analysis was repeated using other storage media such as "Dowtherm A" fluid instead of water, or using solid material beds such as cast iron or rocks. The storage cost for these schemes was found more expensive than the first scheme using the sensible heat of water, and accordingly, they were not discussed further.

(3) *Thermal Conversion Cycle.* Several thermal conversion schemes have been studied, including dual cycles with two different fluids, combined Brayton/Rankine cycle, and heat pipes. The selected scheme is a dual cycle composed of (1) a primary loop with pressurized water as the circulating fluid and consists of the collectors, storage tanks and a heat exchanger acting as a boiler, and (2) a secondary loop consisting of a conventional steam Rankine-cycle with a steam turbine, a pump, a condenser, and a cooling tower. The collectors will operate in two modes, one during sunshine hours (approximately 8 hr) and one during nighttime hours (approximately 16 hr). The flow is regulated during sunshine hours so that approximately 1/3 of the flow is delivered to the steam heat exchanger of the secondary loop and 2/3 is delivered to the thermal storage tanks. During nighttime hours, the hot water is delivered from thermal storage to the steam generator.

(4) *Cost Comparison.* Table 4 shows an estimate of the costs for both approaches. Approach (1) was found less expensive than approach (2) and was selected for comparison with the wind-hydrogen subsystem previously studied. However, *neither of the approaches is acceptable* since they possess very long payback periods (~ 30 years) at very low overall efficiency of energy conversion. A cost comparison between the wind-hydrogen subsystem module and the solar-hydrogen subsystem module producing a nominal hydrogen capacity of 300 kW_t is listed in Table 5. A comparison between the 10-year life cycle

cost and the amount of fuel savings in each scheme shows very clearly that neither is acceptable. Future efforts should be addressed to the direct utilization of either solar or wind power conversion to electrical or mechanical forms.

VIII. Waste Heat Utilization Subsystem

A. Subsystem design

Assuming that the existing diesel generator power plant at Goldstone runs on a continuous basis, a feasibility study was made to convert the plant to a total energy-system to heat, cool and power the facilities. The present system utilizes power from commercial sources and burns fuel for heating and cooling. Waste heat in the cylinder jacket cooling water and in the exhaust gases would be utilized in the form of hot water or steam to provide cooling for the major-load buildings via an absorption refrigeration unit. Electric power would be used to heat and cool minor-load buildings and to power all lights, fans, etc. It was found that it is impractical to modify the existing diesel engine units to accommodate for steam formation in the cylinder jackets. Therefore, only the hot water utilization was studied and costs determined for the DSN stations (DSS 11, DSS 12, DSS 14) and the Mojave and Apollo stations. The energy consumption data for each station is listed in Tables 7 and 8. These data were used as a rough basis for sizing the new components even though the present loads were reduced due to the current energy conservation efforts. The estimated cost includes the capital investment of the absorption refrigeration units, heat exchangers, cooling tower, new chilled water and hot water lines. Comparison of the 10-year life-cycle cost between the existing system with its electric and fuel power purchased from commercial sources and the proposed system, which is continuously operated for electric power production and utilizing the waste heat for HVAC support, showed that the second system is more expensive than the first one by 26 to 73%.

B. Evaluation of Dual Fuel Operation of Diesel Engines

Should a hydrogen economy be implemented at the Goldstone site, it may be advantageous to convert the existing diesel-engine generators from diesel oil to hydrogen fuel. The use of gaseous hydrogen as a fuel for internal combustion engines was first used by Erren in the 1930's in Germany, using hydrogen injection in an engine following the diesel cycle. Development work is continuing today, based on the current national energy situation. A study was initiated by the DSN Engineering Section at JPL and performed at Cornell University, Ithaca, N.Y., to demonstrate the feasibility of this concept. The test results (Ref. 11) from an experimental CFR diesel engine, were generally favorable and the following comparisons were made between hydrogen and diesel oil as fuels: (1) the indicated and brake horsepower were comparable, (2) the cycle efficiency was comparable, and (3) the peak cylinder pressure was almost the same for both cases. A newly designed hydrogen injector, controlled and activated by the pressure pulse of the diesel fuel injection system, was successful and provided a rapid fuel changeover capability. Very high compression ratios (25.7:1) were used in the tests without knock problems. Despite the questions of reliability, crankcase explosion hazards, modifying the cooling system, and life of different components, the study has proven that it is technically feasible. Regarding cost, the dual fuel operation of diesel engines appears to be more expensive as a result of several modifications to the existing units, such as special turbocharging system, new cylinder heads, and hydrogen fuel safety system controls. The estimated cost of converting one unit to dual fuel is about $30,000 and the recommendation of its implementation is totally dependent on whether or not a hydrogen economy is implemented in the first place.

IX. General Conclusions

The following general conclusions have been reached:

(1) The subsystems and their components of Goldstone solar energy system, as illustrated in Fig. 1, have been studied sufficiently to enable the evaluation of their performance and cost effectiveness.

(2) In the solar collection subsystem, five types of commercially available solar collectors were evaluated. It was then generalized that no collector presently available or in an advanced state of development can support a thermal load on an economically attractive basis as compared to fossil fuels at current prices. However, the current research for an economic solar-assisted HVAC system will continue, as this system will become economically feasible with the rising prices of fossil fuel.

(3) The first concept of a solar heating and cooling subsystem configuration, as described in Fig. 2, was selected based on its current adoption nationwide and on the fact that all of its components are commercially available. The conceptual system would serve the four major load buildings at DSS 12. The results were not favorable since the payback period is 29 years. The cost is dominated by the alterations to the existing systems piping, ducts, fan coil units, etc., to convert to a system with underground chilled water transmission line. These costs will be in addition to the cost of new foundations and connections

for the central collector field near the Station entrance. Distributed refrigeration units utilizing the large roof area of each major load building may save some of the above cost, but it is still not economical.

(4) An alternate study of the solar heating and cooling subsystem using the Owens-Illinois tubular collector instead of NASA-Honeywell flat-plate type was made. The collector area and cost were found comparable and in the range of 15% of the total project cost.

(5) The power generation subsystem presented in Fig. 4, utilizing solar or wind power, was found economically unacceptable and it is recommended that a hydrogen generation linkage be dropped from the Goldstone solar energy system objectives. The payback period of a distributed wind-hydrogen subsystem was found to be 31 years and has an overall wind-to-hydrogen to diesel power conversion of less than 5%, as shown in Fig. 4. The payback period will be reduced to 14 years if the hydrogen linkage is deleted and a direct conversion from wind-to-electric energy is made, providing an overall conversion efficiency of 29%. Similar improvements can be made for the solar-hydrogen subsystem. The payback period is reduced from 25 years with water electrolysis to 11 years when the hydrogen link is deleted, and the corresponding overall conversion efficiency is increased from less then 1 to 4.5%.

The high cost of converting valuable electric energy (by solar-Rankine power cycles and wind turbine generators) into thermal energy (in the form of hydrogen production), then burning the hydrogen as a fuel in the diesel engines to reconvert it into electric energy (as a power output from the diesel-generator), is a highly inefficient method of energy conversion. A sequence of the energy losses in each step is presented in Fig. 4, and the effect on the payback period of the project if the hydrogen generation is eliminated is given in Tables 2-4. The effect of high cost and low efficiency of the intermediate components would preclude the economic viability even with the most advanced techniques. Future solar or wind electric power production will be limited to the direct use of electric energy instantly as generated or through energy storage and leveling devices. Meanwhile, if the need for a continuous operation of the standby diesel engines prevails, the alternate to fossil fuel would be alcohol, methane or even hydrogen brought about by the utilization of solid waste and organic residues through catalytic chemical reactions only.

(6) Dual fuel operation of diesel engines using both diesel oil and hydrogen appears to be technically feasible, but more costly. Several modifications to the existing engines have to be made with an estimated cost of $30,000/engine. Its use depends essentially on whether or not a hydrogen economy is feasible at Goldstone.

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Table 1. Cost analysis of the solar heating and cooling subsystem

	Cost, $	Percent of Total
Solar collectors, 1600 m^2 supports and foundation @ $150/$m^2$	240,000	15
5 absorption refrigeration units 25 ton each @ $11,200 each	56,000	3
2 stratified storage tanks (hot and cold) of 156 m^3 each	87,000 (hot) 60,000 (cold)	5 4
Fan-coil units and duct work	295,000	18
Piping, valves and insulation (50% of that is associated with collector loop)	727,000	45
Pumps, motors, controls, accessories, house equipment	167,000	10
Total installed cost (1976 prices)	$1,632,000	100
Annual fuel cost (15% of total demand 1.8×10^6 kWh_t) @ $0.015/$kWh_t$	4,000	
Annual electric power savings (382,000 kWh_e/yr)[a] @ $0.0384/$kWh_e$	14,600	
Annual fuel savings for heating (40,300 kWh_t/yr) @ $0.015/$kWh_t$	600	
Net annual savings	11,200	
Payback period (@ 10% energy escalation rate) and based on zero maintenance cost differential between existing and new system	29 years	

[a]Based on a cooling load of 1.146×10^6 kWh_t and coefficient of performance of the existing air-cooled unit of 3.

Table 2. Cost of a "centralized" wind-hydrogen subsystem (for 314 kW_t of hydrogen delivered)

Installation cost	Cost, $
4 electrolyzers (atm tank type) of 138 kW_e/78.5 kW_t capacity each @ $95,000 each.	380,000
10 units of wind-turbine generator (ac) (vertical axis-type) each rated at 200 kW_e and a local annual output of 120,000 kW_e hr/yr each @ $110,000 each	1,100,000
Power storage cost (flywheels, batteries, etc.) estimated @ $50/$kW_e$ for the whole plant (2000 kW_e)	100,000
Electrical transmission network (transformers, transmission lines, etc.) 2000 kW_e capacity, 13.2 kV	94,000
	$1,674,000
Operation and maintenance cost	
10-year O&M cost @ 10% of installation cost	167,400
10-yr life cycle cost	$1,841,400
Annual Fuel Savings	
(314 kW_t for 6 hr/day @ $0.015/$kWh_t$)	10,315
Payback period @ 10% energy escalation	30 years
Total installation cost of a centralized wind-turbine power plant with no hydrogen production	1,294,000
Annual electrical energy savings (120,000 kWh_e per turbine @ $0.0384/$kWh_e$)	46,080
Payback period @ 10% escalation rate	14 years

Table 3. Cost of a "distributed" wind-hydrogen subsystem (for 314 kW_t of hydrogen delivered)

Installation	Cost, $
10 electrolyzers (atm tank type) of 55 kW_e/31.4 kW_t capacity each @ $56,000 each	560,000
10 units of wind-turbine generator (dc) (vertical axis type) each rated at 200 kW_e and a local annual output of 120,000 kWh_e/yr each @ $130,000 each (increased cost for dc generation)	1,300,000
Power storage cost (estimated at $50/$kW_e$) for a plant 2000 kW_e capacity	100,000
Total installation cost	$1,960,000
10-year operation and maintenance cost @ 10% of installation cost	196,000
10-yr life cycle cost	$2,156,000
Annual fuel savings (314 kW_t for 6 hr/day @ $0.015/$kWh_t$)	10,315
Payback period @ 10% escalation rate	31 years
Total installation cost of a distributed wind turbine power plant with no hydrogen production	1,400,000
Annual electric energy savings (120,000 kWh_e per turbine @ $0.0384/$kWh_e$)	46,080
Payback period @ 10% escalation rate	14.6 years

Table 4. Cost of a solar-hydrogen subsystem producing 300 kW_t of hydrogen

Approach (1)	Cost, $
Collectors cost: 16,250 m^2 @ $127.7/$m^2$	2,075,000
Storage cost: storing 40,080 kWh_t/day @ $21.9/$kW_t$hr	877,000
One complete Rankine-cycle engine (heat exchanger, turbine generator, condenser, cooling tower, control and piping). Net output 526 kW_e	300,000
One electrolyzer (composed of 10 small units of 30.0 kW_t each)	560,000
Total installation cost	3,812,000
10 year operation and maintenance cost @ 10% of installation cost	381,000
Ten-year life cycle cost	4,293,000
Approach (2)	
Collectors cost: 16,253 m^2 @ $127.7/$m^2$	2,075,000
3 installed Rankine-cycle engines (complete with heat exchanger, turbine-generator, condenser, cooling tower, etc.) Net output 526 kW_e each. Each @ $300,000	900,000
3 electrolyzer units complete with accessories @ $560,000 each	1,680,000
Total installation cost	4,655,000
10-yr operation and maintenance cost @ 10% of installation cost	466,000
Ten-year life cycle cost	5,121,000
Annual fuel savings (300 kW_t for 24 hr/day @ $0.015/$kWh_t$)	39,420
Payback period of Approach (1)	24.8 years
Payback period of Approach (2)	26.8 years
If the solar power subsystem is installed without electrolyzers or hydrogen production	
Annual electrical savings (526 kW_e for 24 hr/day @ $0.0384/$kWh_e$)	176,940
Approach (1)	
Installation cost	3,252,000
Payback period	10.9 years
Approach (2)	
Installation cost	2,975,000
Payback period	10.4 years

Table 5. Cost comparison between a wind-hydrogen subsystem module and a solar-hydrogen subsystem module each having 300 kW_t nominal capacity of hydrogen

A. Wind-hydrogen subsystem[a]	Cost, $
Total installation cost (10 electrolyzers, 10 wind-turbine dc generators, power storage), actual output = 314 kW_t hydrogen.	1,470,000
10-yr operation and maintenance cost @ 10% of installation cost as in Table 3	196,000
Ten-year life cycle cost	$1,666,000
Annual fuel savings @ $0.015/$kWh_t$	10,315
10-yr fuel savings	103,200
Payback period @ 10% escalation	31 years
B. Solar-hydrogen subsystem[b]	
Total installation cost (collectors, thermal storage tanks, Rankine power cycle, 10 electrolyzers)	3,812,000
10-yr operation and maintenance cost @ 10% of installation cost	381,000
Ten-year life cycle cost	4,293,000
Annual fuel savings @ $0.015/$kWh_t$	39,420
10-yr fuel savings	394,200
Payback period @ 10% escalation	24.8 years

[a]This is the "distributed" wind-hydrogen subsystem presented in Table 3. A discount of 25% of the installation cost is superimposed provided that this configuration is mass produced.

[b]This is the solar-hydrogen subsystem of approach (1) presented in Table 4.

Table 6. Annual energy consumption at Goldstone (1973 data)

Site	Load								
	Total gas heating, kWh_t	Total electrical heating, kWh_t	Total heating energy (gas and electrical), kWh_t	Electric consumption (excluding heating), 10^6 kWh_e	Average electric load (excluding heating), kW_e	Cooling load consumption, kWh_t	Average cooling load, kW_e	Peak cooling load, tons	Average electric load (excluding heating and cooling), kW_e
DSS 11 (Pioneer)	522,100	74,400	596,500	2.91	332	921,300	45	89	287
DSS 12 (Echo)	3,098,300	122,400	3,330,700	5.20	594	2,255,400	120	188	474
DSS 13 (Venus)	333,900	66,700	400,600	2.17	248	718,300	27	62	221
MW test facility	116,400	--	116,400	0.20	23	106,600	4	10	19
DSS 14 (Mars)	--	538,200	538,200	8.06	920	1,744,800	69	122	851
Apollo	--	1,116,800	1,116,800	6.42	732	3,314,000	136	151	596
Mojave	--	678,100	678,000	3.04	347	1,555,700	74	95	273
Total	4,070,700	2,596,600	6,667,300	28.00	3196	10,616,100	475	717	2721

Table 7. Annual heating and cooling requirements of major load buildings of GSCC

Station	Pioneer			Echo			Mars		Mojave/Apollo		
Major Load Building	G-1	G-18	G-21	G-26	G-33	G-38	G-80	G-86	MS-8	A -1	A-2
Annual heating requirement, kWh_t	48,200 (gas)	194,200 (gas)	308,800 (gas)	234,600 (gas)	201,800 (gas)	685,700 (gas)	282,200 (elec)	186,800 (elec)	397,500 (elec)	769,600 (elec)	287,700 (elec)
Annual cooling requirement, kWh_t	713,800	81,000	181,300	835,900	302,300	765,000	357,000	1,261,000	1,356,000	2,880,000	349,600
Percentage of station heating requirement, %	15.2	61.3	16.55	12.57	10.81	36.75	52.42	34.69	58.6	68.89	25.75
Total percentage of station heating	76.5			76.68			87.11		58.6	94.64	
Percentage of station cooling requirement, %	77.49	8.79	8.04	37.06	13.4	33.92	20.47	72.27	87.15	86.92	10.55
Total percentage of station cooling	86.28			92.42			92.74		87.15	97.47	
Peak cooling load of major buildings, tons	69.3			163			106		193		
Peak heating load of major buildings, kW_t	200			460			168		–		
Installed cooling capacity, tons	191 (DX type)			353 (DX type)			(260) total w. chilled DX		323		
Installed heating capacity, kW_t	483 (gas-fired)			678 (gas-fired)			250 (elec)		389 (elec)		

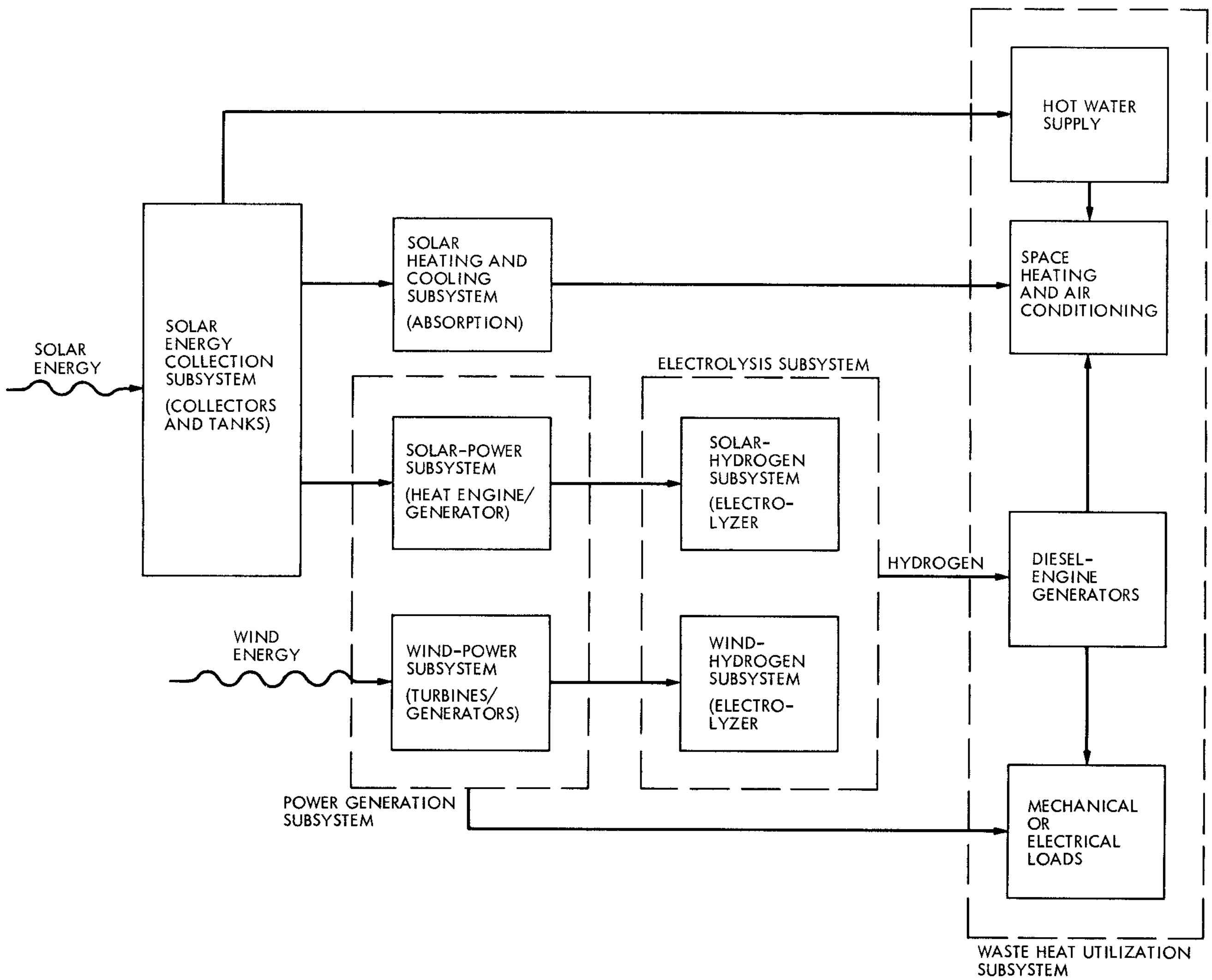

Fig. 1. Outline of Goldstone solar energy system

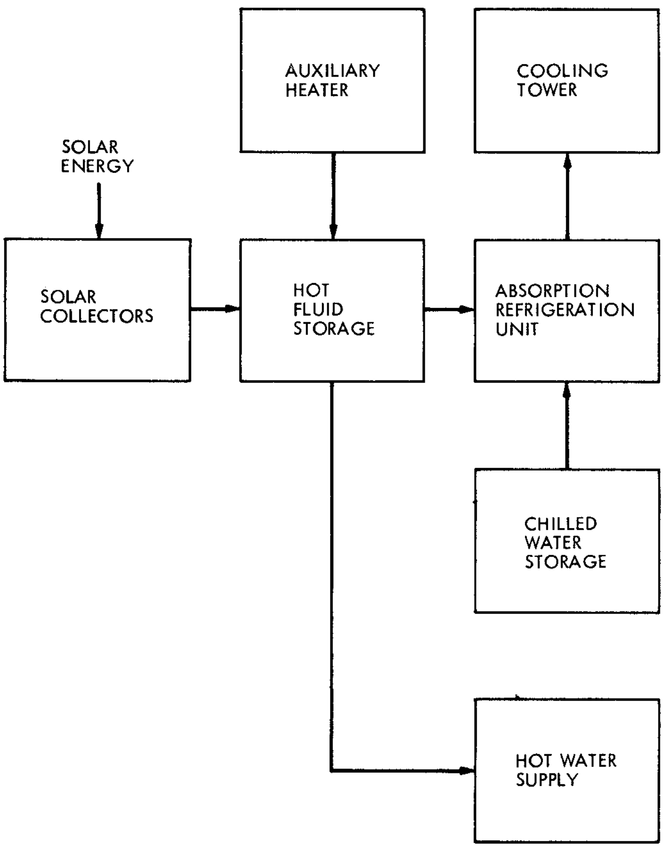

Fig. 2. Solar heating and cooling subsystem

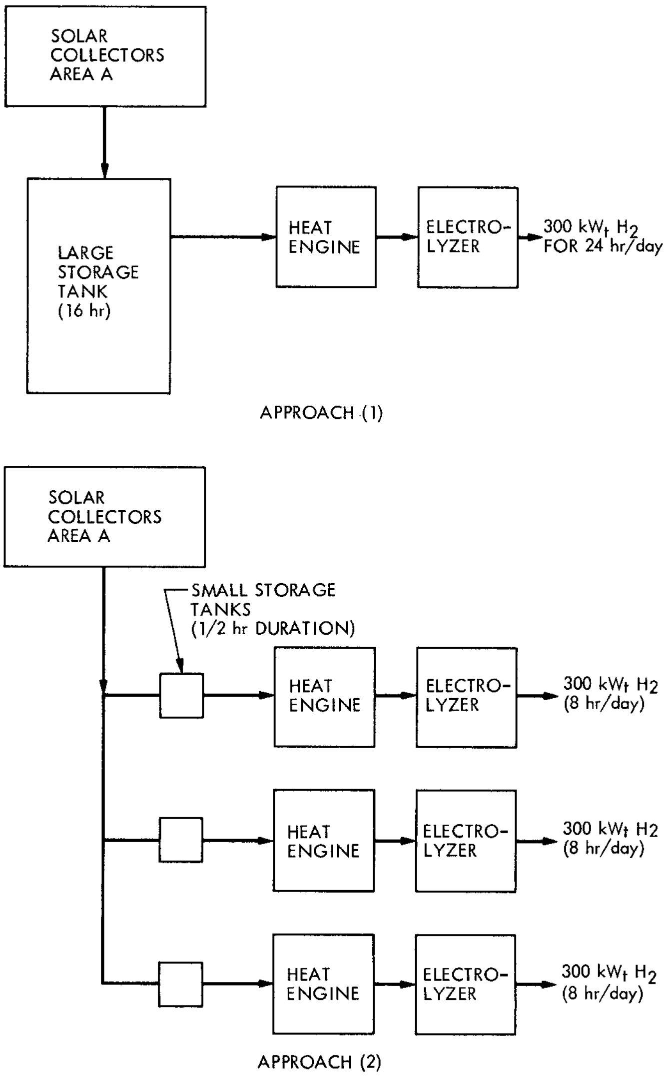

Fig. 3. Comparison of Approaches (1) and (2) of the solar hydrogen subsystem

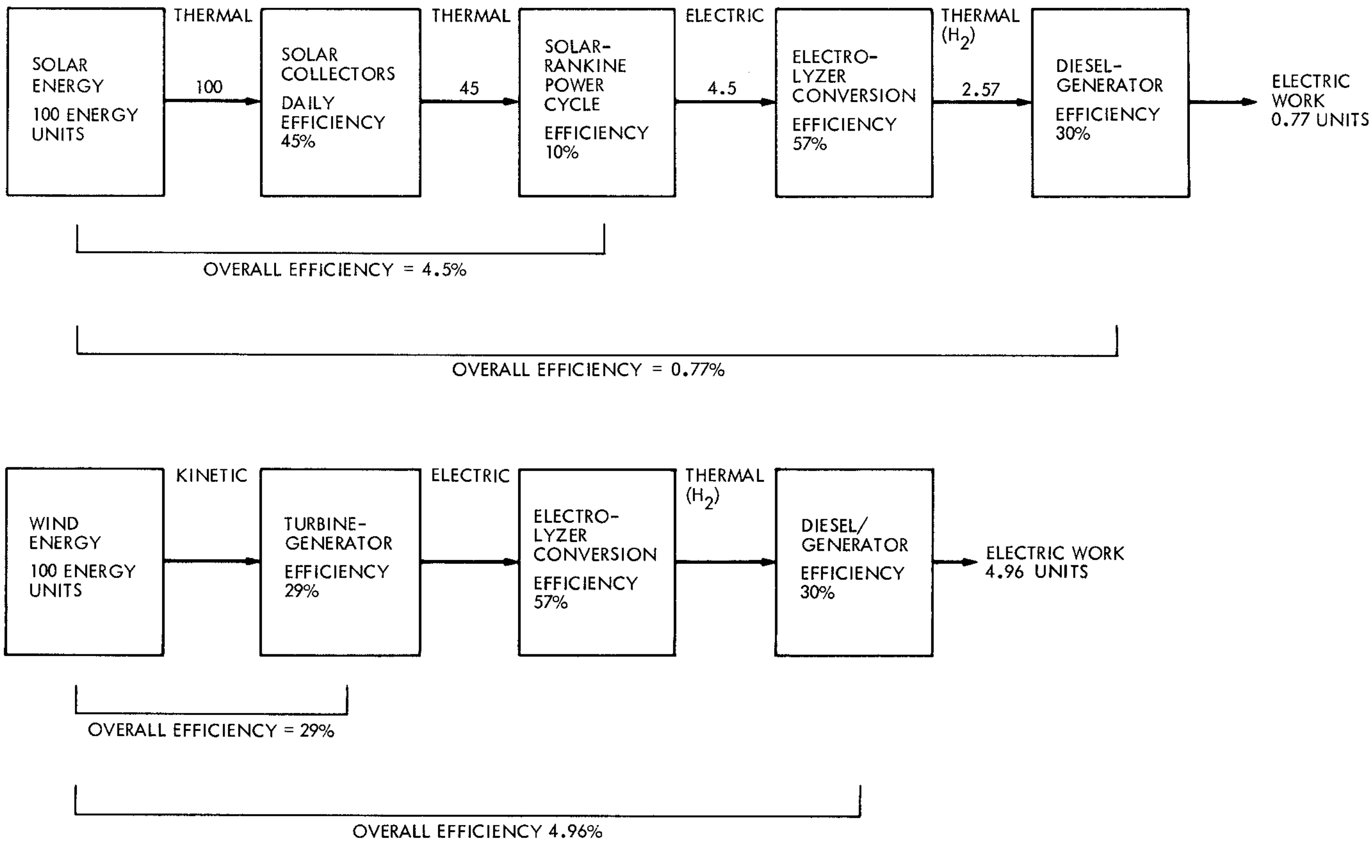

Fig. 4. Efficiency of cascaded energy systems; solar and wind to hydrogen conversion